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Complex Hydraulic Fracture Behavior in Horizontal Wells, South Arne Field, Danish North Sea

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Abstract

This paper provides a case history of complex fracture behavior in Horizontal wells in the South Arne Field, Danish North Sea (9500 ft TVD, chalk formations).[1] The first three propped fracture treatments attempted in the South Arne Field "screened-out" very early in the design due to excessive fracture complexity and fluid leakoff. A detailed study of the rock mechanical properties, wellbore stress & fracture initiation characteristics, far-field stress regime & fracture orientation, and fluid leakoff behavior was integrated with fracture modeling studies to evaluate this problem. These studies were used to improve the fracture treatment strategy for future wells, resulting in essentially 100% success placing the designed proppant volumes and achieving aggressive tip screen-outs (TSOs) on over 60 fracture treatments.

Introduction

The South Arne field is located in the northern part of the Danish sector of the North Sea. The structure is an elongated Cretaceous inversion ridge situated on the western margin of the Tail-End Graben. The reservoir rock is high porosity/low permeability chalk of Maastrichtian and Danian age, comprising the Tor and Ekofisk formations, respectively. A hard, low porosity interval at the bottom of the Ekofisk formation separates the two formations. Tor formation permeabilities range from 0.2 to 4 mD, whereas the Ekofisk formation permeabilities range from 0 to 0.7 mD. Virgin reservoir pressure is 6300–6400 psig and reservoir temperature is 240 deg F. The reservoir is low to moderately naturally fractured. The combined thickness of the Ekofisk and Tor reservoir varies from 25 to 120m.

The direction of maximum horizontal stress is approximately northwest to southeast (**Figure 1**). The well locations are also shown in Figure 1. The horizontal section targets the Tor formation and is typically about 1800 meters in length.[1] The completion method selected for the five wells allows each zone to be mechanically isolated from the rest during both stimulation & production. The wells were completed using propped fracture treatments in each zone.[2,3] The work string is used both for perforating, stimulating and isolating the individual zones.[4] The annulus between the work string and the liner is open during stimulation, providing excellent bottom hole pressure measurements using the static annulus pressure.

Unlike other North Sea Chalk reservoirs where the primary problems are tortuosity and multiple fractures,[5,6,7] the South Arne reservoir also suffers from the apparent activation of natural fractures or fissures, leading to excessive fluid loss that may result in an inability to place proppant. The potential for this behavior was identified during the initial rock mechanical studies (SA-1C) and verified using both fracture modeling and G-function analyses. Several changes in the fracture treatment strategy were evaluated in an attempt to reduce fracture complexity and control fluid loss into natural fractures/fissures: reducing the perforated interval, initiating the fracture with cross-linked gel containing 100-mesh sand, reducing proppant size, avoiding areas of high natural fracture density, and eliminating the mini-frac.

Overview

The first fracture treatments in South Arne were conducted in the SA-1c well, zones 2 and 3, in May 1998. However, these initial attempts were unsuccessful, with the zone 2 treatment screening out on a 1-ppg 16/30-mesh proppant slug and the zone 3 treatment screening out with only 130 Klbs of 16/30-mesh proppant in the formation. A detailed rock mechanics study indicated that fracture initiation procedures and the interaction of the hydraulic fracture with pre-existing natural fractures/fissures resulted in severe fracture complexity and/or excessive leakoff. A second set of "demonstration" fracture treatments were conducted in the SA-4 well in December 1998 to evaluate the effectiveness of changes in perforating, fracture initiation, and execution strategies.

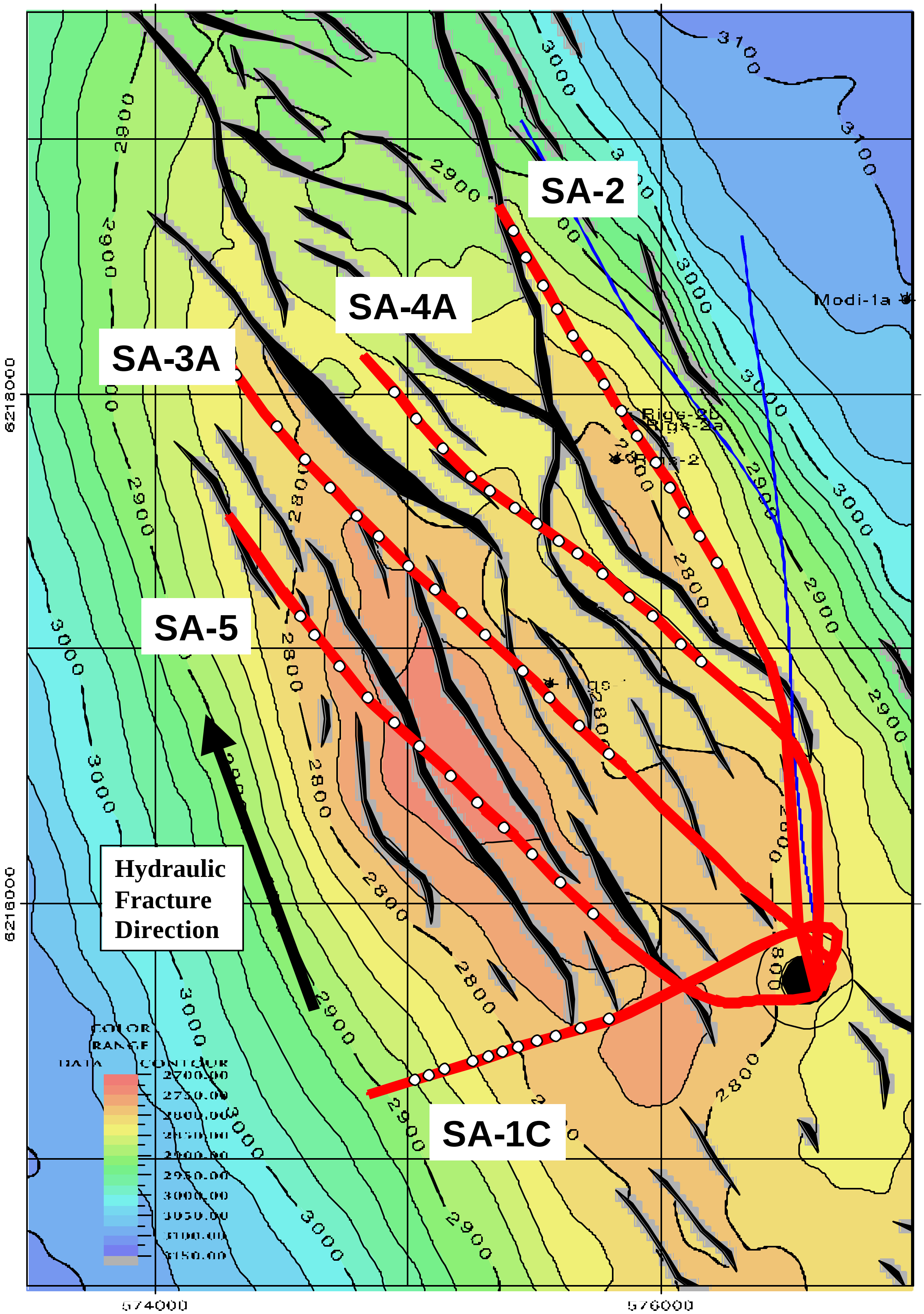

Figure 1 – South Arne Field Map (top Tor depth)

The first treatment in the SA-4 well (zone 1) utilized a high viscosity cross-linked gel to initiate the fracture followed by a 1-ppg 100-mesh sand stage to reduce fracture complexity and control fluid loss. 20/40-mesh proppant was pumped in zone 1 to reduce the potential of a screen-out due to insufficient fracture width. A mini-frac shutdown was not performed and the perforation interval was limited to 1-ft in to reduce fracture complexity. Although the zone 1 fracture treatment program was considered very conservative, the treatment exhibited significant pressure responses to 20/40-mesh proppant slugs and began to screen-out when the first proppant stage reached the formation, even though fracture initiation and propagating pressures were not excessive. Only 100 Klbs of 20/40 RCS, about 20% of the designed proppant volume, was placed in the formation. The post-treatment analysis indicated that excessive fluid loss resulted in insufficient fracture width to place the designed proppant volume.

The second treatment in SA-4 (zone 2) was planned very similar to zone 1. However, it was hypothesized that increasing the concentration of 100-mesh sand could potentially control excessive fluid loss into natural fractures or fissures that may be dilated during the fracturing process. Therefore, the concentration of 100-mesh sand was increased to 4-ppg (ramp 1-4 ppg) during the displacement stage. The SA-4 Zone-2 initiation was pumped as designed and a 1-3 ppg 20/40-mesh proppant slug easily passed through the perforations and injection pressures were not excessive. However, the annulus was plugged during fracture initiation and therefore an unplanned shutdown was required to clear the annulus. After the annulus was cleared the treatment was re-initiated and second 1-6 ppg 20/40-mesh proppant slug was pumped which indicated severe proppant entry problems, almost screening out when the slug reached the perforations. A second shutdown was required to evaluate potential solutions to the proppant entry problems.

The SA-4 Zone-2 treatment was re-initiated a second time and a 1-4 ppg 100-mesh slug was pumped to reduce fracture complexity and control excessive fluid loss. The second re-initiation using 1-4 ppg 100-mesh sand in the pad was successful and no proppant entry problems were indicated when the 1-4 ppg 20/40-mesh proppant reached the perforations. The SA-4 zone 2 *propped* treatment was pumped as designed, placing 450 Klbs of 20/40 RCS at concentrations up to 12-ppg while also achieving a TSO pressure increase of about 500 psi.

The SA-4 zone 3 treatment was designed using the insights gained from zone 2. The zone-3 treatment design included a 1-4 ppg 100-mesh and slug in displacement stage that was followed by a 1-4 ppg proppant slug. A mini-frac was not included in the zone-3 treatment design due to the problems encountered during the "un-planned" shutdown during the zone 2 treatment. The zone 3 treatment was pumped as planned, placing 500 Klbs of 20/40-mesh RCP at concentrations up to 15-ppg. A TSO net pressure increase of about 500 psi was achieved during the zone-3 treatment. The results from the three "demonstration" propped fracture treatments in SA-4 confirmed that propped fracturing could be routinely successful in South Arne and provided essential data for future designs. In addition, the SA-4 treatments showed that modest TSO pressure increases could be achieved with relatively large pad sizes (about 35% pad fraction).

The next well that was completed was the SA-5b in March-April 1999. Twelve zones were successfully completed using propped fracture treatments. The SA-2, SA-4, SA-1c, and SA-3 were "batch" completed between August-1999 and January-2000. A total of 64 zones were prop fracture stimulated using a total of 49 million pounds of proppant. Although the first three propped-fracture treatments in South Arne were unsuccessful, resulting in very early screen-outs, only three additional screen-outs were encountered during the remaining 61 propped fracture treatments.

General Operational Procedures. All South Arne propped fracture treatments were pumped down a work string with the annulus "live" (no packer) using the rig-based completion system that allows each zone to be fracture stimulated and then isolated for optimum reservoir management flexibility.[4] The "live" annulus provided accurate bottom hole pressure (BHP) measurements, while also allowing stimulation fluids to be circulated to within close proximity of the perforated interval. Each zone was perforated using 6-spf over a 6-ft interval. Typical South Arne fracture treatments included the following stages:

1. Fill surface lines to the wellhead with cross-linked gel.
2. Circulate cross-linked gel to within 3-5 bbls of the bottom of the work string. Add 1-4 ppg 100-mesh sand to later portions of the circulation stage (typically the portion that will remain in the vertical section of the work string).
3. Close the BOP rams and perform a cross-linked fluid mini-frac injection with a 1-3 ppg proppant slug in the final portion of the injection.
4. Flush the mini-frac with linear gel and shutdown just as the proppant slug passes through the perforations.
5. Analyze the mini-frac data to determine near-wellbore tortuosity, fracture complexity, and fluid loss behavior. Adjust pad size and proppant schedule based on the mini-frac analysis.
6. Pump the main treatment cross-linked fluid pad, with the inclusion of a 1-4 ppg 100-mesh slug and 16/30-proppant slugs as/if necessary.
7. Pump the main treatment 16/30 sand stages as designed using cross-linked fluid. Switch to RCP if the tip screen-out (TSO) trend indicates that the designed proppant volume cannot be "reliably" pumped.
8. Pump the main treatment RCP stages as designed using cross-linked fluid if an early switch to RCP was not made in step 7.

9. Flush the treatment with friction-reduced completion brine (typically 1.6 S.G.) as designed or initiate flush early if the TSO trend indicates that all the RCP cannot be pumped.
10. Shutdown and monitor pressure decline for 10-30 minutes.

The above procedures were developed based on the integration of historical North Sea Chalk fracture stimulation practices[2-7] and specific South Arne data and experience[1]. The subtleties of the fracture initiation and re-initiation (after the mini-frac) procedures can be critical to the success of the treatment and are discussed in detail in the following sections of the paper. All SA fracture treatments utilized fresh-water-based 35-50 lbm/Kgal concentrations of guar or HPG gelling agents and borate cross-linkers (typically higher gel loadings in the pad, with reduced gel loadings as the treatment progresses). 2% KCl water was used as the base fluid for all stimulation treatments and surfactant used to prevent emulsions and improve water recovery. Appropriate breaker loadings and types were used to degrade the cross-linked gels.

SA-1C Zones 2 & 3

The basic layer depths and rock properties for zone 2 & 3 are shown in **Table** 1. These were the first propped fracture treatments attempted in the South Arne field. The general treatment procedures discussed above evolved considerably as experience was gained from these initial treatments.

SA-1C Zone-2. The treatment data from the SA-1C Zone-2 job are shown in **Figure 2**. The SA-1C Zone-2 mini-frac utilized cross-linked fluid, circulated to the bottom of the work string, to initiate the fracture.

Table 1 – SA-1C, Zone 2 & 3 Layer Properties

Approximate Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9413	Middle Ekofisk	4.0
9459	Lower Ekofisk	4.4
9482	Tight zone	5.2
9512$^{(1)}$	Tor	1.5
9733	Shale	3.0

Note (1): Zone 2 perfs = 9594-ft, Zone 1 perfs = 9540-ft

The mini-frac pressure response was not unusual, exhibiting a breakdown pressure of about 3500-psi that declined continually during the cross-linked gel injection to 2000-psi at 43 bpm at the end of the mini-frac (Figure 2, **Table 2**). The mini-frac pressure decline showed no unusual behavior with respect to net pressure and fluid efficiency.

However, when the fracture was re-initiated the annulus pressure was substantially higher and injection rate was initially limited to 10-15 bpm due to the annulus pressure limitation of 4000-psi. Two proppant 16/30-mesh slugs were pumped during the pad, 1-ppg and 3-ppg concentrations. The injection increased during the pad to 30 bpm, but the treatment screened-out when the 1-ppg proppant slug reached the perforations.

The dramatic difference in annulus pressure (reflected BHP) between the mini-frac and propped treatment pad indicated that a significant change had occurred between the two injections. Two scenarios were considered:

- Perforation plugging and/or collapse, or
- Increased fracture complexity.

The ***preliminary*** evaluation of the zone 2 treatment data indicated that the most likely explanation for the screen-out was perforation plugging due to 100-mesh sand that remained in the wellbore after the mini-frac. In addition, due to the abrupt screen-out, there was some difficulty removing the cross-linked gel from the work-string. Therefore, the injection procedures for zone 3 were modified, eliminating the cross-linked gel and 100-mesh sand from the initial injection.

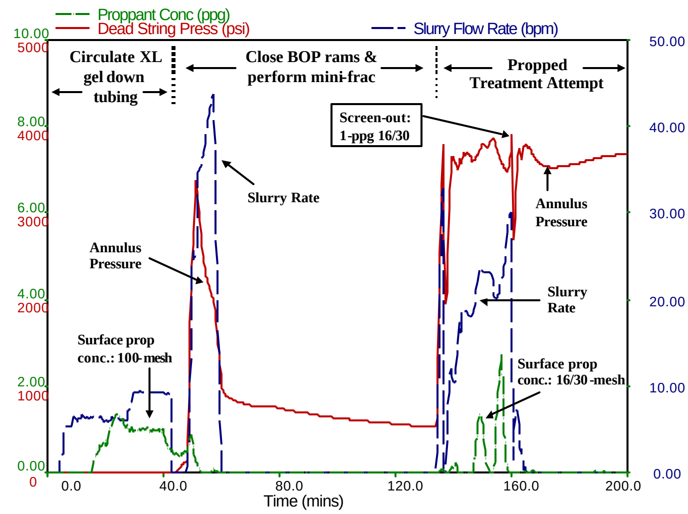

Figure 2 – SA-1C zone 2 treatment data

Table 2 – Summary of SA-1C Zones 2 & 3

Injection	Pressure (psi)	Rate (bpm)	ISIP (psi)	Tortuosity (psi)	Vol. (bbl)
Z2, Inj.#1	2000	43	1050	1000	335
Z3, Inj.#1^{1}	2700	40	1000	1700	300
Z3, Inj.#2^{1}	3840	36	1500	2340	380
Z3, Inj.#3^{2}	1260	48	650	610	490
Z3, Inj.#4^{3}	2360	41	1900	460	1040

Notes:(1) Injection performed using 45 lb linear gel only
(2) Injection included 125 bbl of 15% HCl
(3) Injection included 500 bbl of borate XL gel containing 8,000 lbs of 100-mesh sand followed by 4000 lbs of 16/30-mesh proppant.

SA-1C Zone-3. The results from SA-1C zone 3 propped fracture treatment are shown in **Figure 3**. The zone 3 treatment data are summarized in Table 2. Due to the problems encountered with zone 2, several options were included in the pumping procedures, including the use of HCl in the event injectivity was limited. The initial injection into zone 3 (Inj. #1) was performed using 45 lb linear gel. The injectivity into zone 3 was somewhat lower than zone 2, but the instantaneous shut-in pressures (ISIPs) are very similar (Table 2). The tortuosity or near-wellbore friction is much higher for zone 3 (injection #1). The increased tortuosity is probably due to fracture initiation with linear gel.

The G-function plot of the pressure falloff after injection #1 is shown in **Figure 4**. The G-function analysis includes the derivative (dP/dG) and superposition (GdP/dG) that can be very helpful in both picking fracture closure pressure and identifying pressure dependent leakoff associated with fissure opening.[8] Figure 4 shows the characteristic behavior of fissure opening (or closing) during the initial portion of the pressure decline.

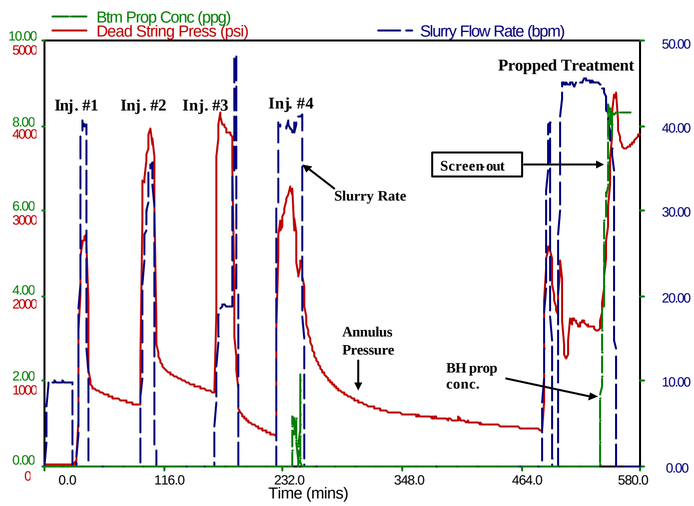

Figure 3 – SA-1C zone 3 treatment data

A second linear gel injection was performed on zone 3 (Figure 3). The second injection exhibited significantly higher annulus pressure and ISIP (Table 2), indicating the fracture complexity and tortuosity had increased from injection #1 to injection #2. The G-function pressure decline analysis for injection #2 is shown in **Figure 5**. Compared to injection #1, the fissure-opening signature is much more pronounced during the injection #2 decline, possibly indicating that additional fissure opening or dilation occurred during injection #2.

Due to the increasing fracture complexity and tortuosity, a third injection was performed in zone 3 that included 125 bbl of 15% HCl. The acid removed much of the tortuosity and fracture complexity as evidenced by the reduction in both injection pressure and ISIP at the end of injection #3 when the acid reaches the formation (Table 2). However, it should be noted that compared to injection #2, the injectivity is significantly lower during the initial portion of injection #3 (before the acid reaches the formation). This is further evidence that fracture complexity and/or tortuosity increase after each subsequent injection.

The G-function pressure decline analysis for injection #3 is shown in **Figure 6**, showing very little "fissure opening" characteristics. Based on the positive results from the acid treatment, a fourth injection was performed as a precursor to the propped treatment.

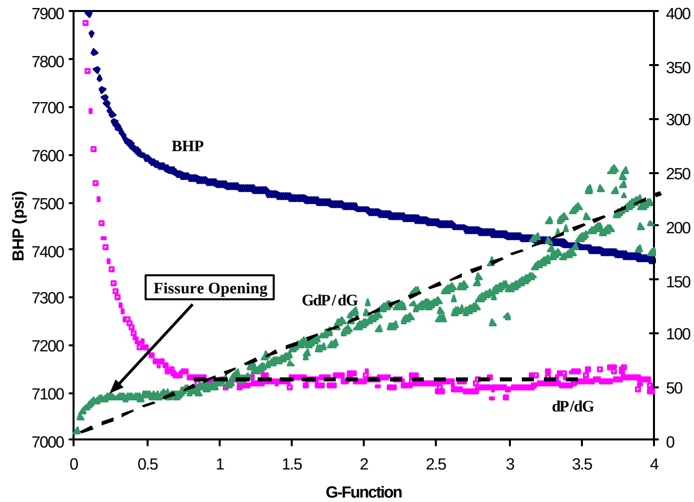

Figure 4 – SA-1C zone 3, injection #1 pressure decline

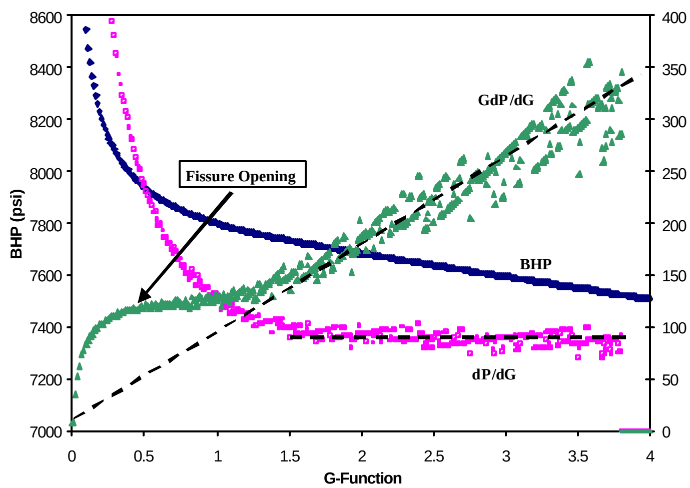

Figure 5 – SA-1C zone 3, injection #2 pressure decline

The fourth injection consisted of 500-bbl of 45-lb cross-linked borate gel containing an 8000-lb 100-mesh sand slug (1-ppg) followed by a 4000-lb 16/30-mesh proppant slug (1-3 ppg). However, the injection pressures during the fourth injection were significantly higher than those at the end of injection #3 (Table 2, Figure 3). Therefore, it appears that fracture complexity and/or tortuosity had again increased between subsequent injections.

The G-function analysis of the injection #4 pressure decline is shown in **Figure 7**, confirming that fracture complexity is high and fissure opening is very evident. It should noted that tortuosity has only slightly increased between injections #3 & #4, but the ISIP has increased from 650-psi to 1900-psi (Table 2).

Discussion of Injections 1-4. The results of the four injections in zone 3 indicated that fracture complexity steadily increases with each subsequent injection of non-reactive fluid. This is evidenced by the increasing ISIPs for injections 1, 2, and 4 – with the ISIP for injection #4 being 900-psi higher than the initial ISIP. The acid injection successfully removed tortuosity and reduced fracture complexity (low ISIP), but the acid did not mitigate the overall problem of increasing fracture complexity with successive injections.

Closure pressure gradient in the Tor formation averages about 0.75 psi/ft, 7150-psi BHP or about 550-psi annulus pressure for zones 2 & 3. Thus, an ISIP of 1900-psi annulus pressure after the forth injection would indicate a net pressure of about 1350-psi in this relatively thick and low modulus chalk formation. This extremely high net pressure indicates severe fracture complexity.

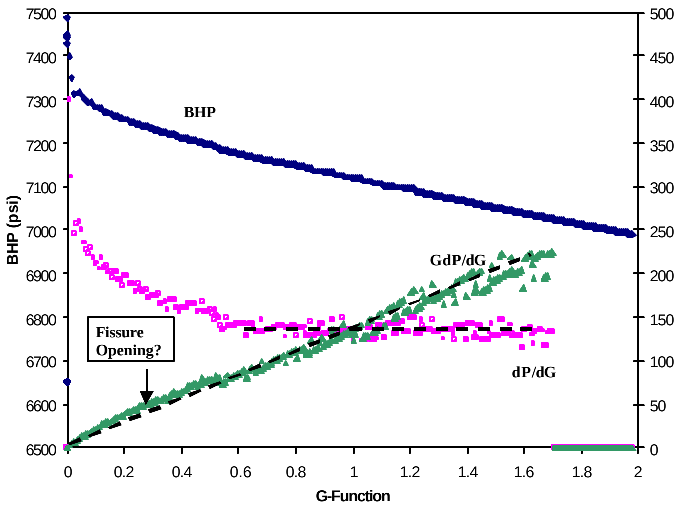

Figure 6 – SA-1C zone 3, injection #3 pressure decline

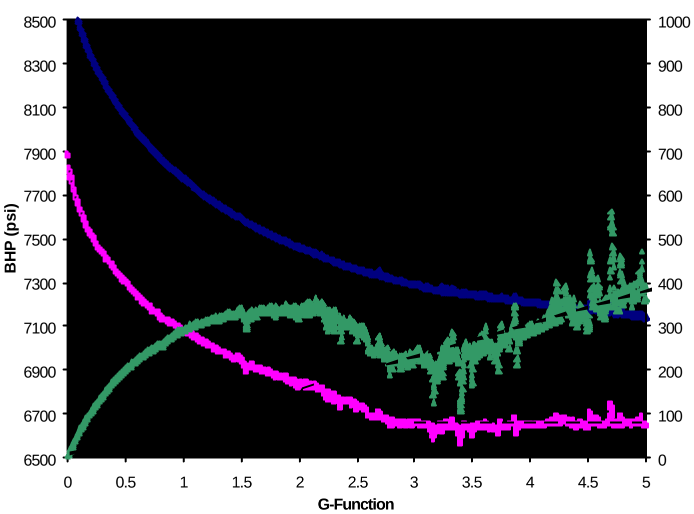

Figure 7 – SA-1C zone 3, injection #4 pressure decline

SA-1C, zone 3 propped treatment. Based on the behavior of injections 3 and 4, the propped treatment design was altered to include an acid stage (175 bbl) prior to the pad stage. The pad design was altered to include 16,000 lbs of 100-mesh sand (1-ppg) followed by a 16/30-mesh proppant slug (8,000 lbs at 1-5 ppg). The intention was to use the acid to reduce fracture complexity and tortuosity and then use the 100-mesh sand to control excessive fluid loss that may result from the acid. The 16/30-mesh proppant slug was included to ensure that no proppant entry problems were present.

The acid stage prior to the pad successfully reduced injection pressures (reducing fracture complexity & tortuosity) and the 1-5 ppg 16/30-mesh proppant slug easily passed through the perforations. Thus, all indications were positive to begin the main proppant stages. However, when the 2-ppg-proppant-stage reached the perforations, a screen-out began. The annulus pressure increased from 1700-psi to the pressure limit of 4000-psi in about 15 minutes, with only 120,000 lbs of proppant pumped (about 15% of the design). The zone-3 propped treatment indicates that excessive fluid loss due to acid injections cannot be effectively controlled using 100-mesh sand.

Discussion of SA-1C zones 2 & 3 results. The results from the initial South Arne propped fracture treatments indicated that fracture complexity could increase substantially after a mini-frac shutdown. The combined results from both zones showed that perforation plugging was not the most likely explanation for the screen-out in zone 2. The mostly likely cause of the zone-2 screen-out was increasing fracture complexity and/or tortuosity due to the mini-frac shutdown and subsequent re-initiation of the fracture using linear gel, which resulted in insufficient fracture width to accept proppant. The zone 3 treatment showed that acid reduces tortuosity and fracture complexity, but increases fluid loss substantially, which results in premature screen-outs. The very complex behavior of SA-1C zones 2 & 3 resulted in a detailed rock mechanics study to better define the reasons for the persistent treatment problems.

Rock Mechanics: SA-1C Evaluation

There was fairly reliable stress data from MDT tests and from image logs. The stress orientation was determined from the MDT and image log analysis. **Table 3** lists the stress and well data. **Figure 8** shows the wellbore orientation with respect to the stress orientation. Natural fractures were evident in an image log at an angle of about 40-60 deg to the preferred fracture plane. Also, a dip-meter log indicated that many natural fractures were encountered with a dominant direction of some 50^{o} with the preferred fracture plane. A smaller fracture set was present perpendicular to this direction.

A MDT-microfrac test showed screen-out behaviour, which can be explained by dehydration of the mud and plugging of the micro-frac. There was however evidence of interaction of the hydraulic fracture with the natural fractures. This indicated that the natural fractures might be opened during fluid injection and propagation of a hydraulic fracture. Also, there was evidence from mud circulation density logs of mud losses that could be due to opening of natural fractures. This observation is important for hydraulic fracture propagation.

Table 3 – SA-1C Stress & Well Data

Well Name: South Arne 1		
Deviation Angle from vertical:	85	(deg)
Azimuth Angle from N:	250	(deg)
Casing OD:	7	(in)
Stress Data:		
Overburden Stress:	9115	(psi)
Max. Horiz. Stress:	8887	(psi)
Min. Horiz. Stress:	7300	(psi)
Reservoir Pressure:	6400	(psi)
Min. Stress Direction:	75	(deg)
Rock Properties:		
Plain Strain Elastic Modulus:	1,000,000	(psi)
Poisson's Ratio:	0.2	()
Tensile Strength:	100	(psi)
Perforation Data:		
Perforation Diameter:	0.42	(in)
Perforated Interval	6	(ft)
Perforation Orientation:	60	(deg)

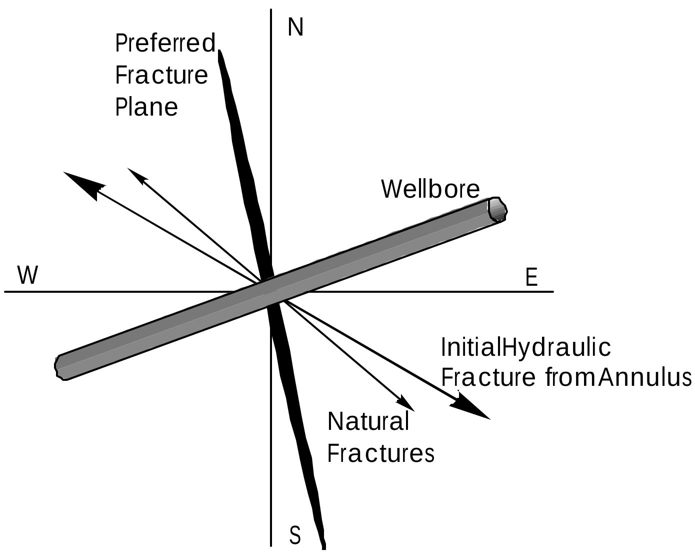

Figure 8: Orientation of wellbore with respect to the preferred fracture plane and the dominant set of natural fractures

Stress on Natural/Shear Fractures. Figure 9 is a Mohr diagram of the stress on the natural fractures. If the pore pressure increases by 900 psi, it becomes possible to destabilize the shear fractures that were observed in the image log. Thus, at typical fracturing pressure it is likely that destabilization occurs. In view of the angle they make with a hydraulic fracture, the natural fractures could be destabilized by the high fluid pressure in shear failure. Once the fracture moves in shear, its conductivity might be increased and they may accept more fluid, thus enhancing the instability. There are two ways that shear fractures can play a role in fracture propagation: near the well, shear fractures may be opened because they coincide with the initial fracture orientation (so they get a high tensile stress). Secondly, a propagating hydraulic fracture may encounter a shear fracture and rather than just crossing it, the hydraulic fracture may follow the shear fracture for some distance. Then, the hydraulic fracture would probably branch off again. If this happens a number of times, multiple branches form and the result will be a very complex fracture. In addition, if shear fractures or natural fractures are destabilized or dilated, the fluid loss could increase dramatically.

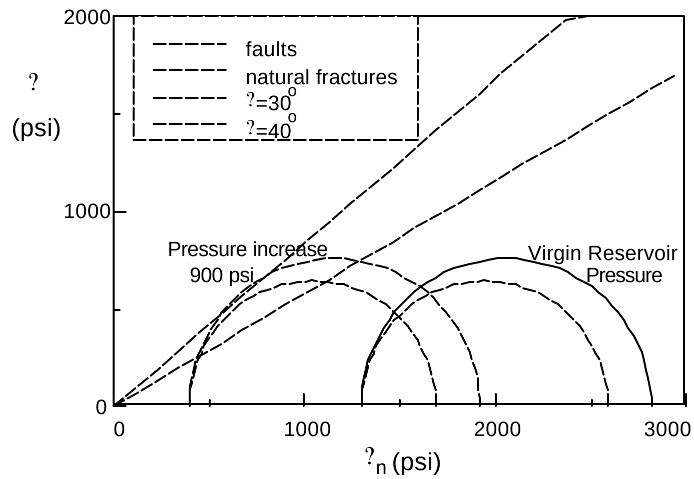

Figure 9: Mohr-Coulomb diagram of stresses in South Arne field

Stress analysis of the fracture initiation in well SA-1c shows that the near-wellbore geometry of hydraulic fractures is likely to be complicated. The main reasons are:

?? The well is almost perpendicular to the preferred fracture plane.

?? Natural fractures have a dominant orientation that coincides with the orientation of starter fractures from the wellbore.

?? Natural fractures may be dilated and result in excessive fluid loss. This problem may be aggravated by multiple injections (mini-fracs) that destabilize the fracture system and increase fracture complexity.

The observed anomalous pressure behaviour in SA-1C, zones 2 & 3 is most likely due to:

?? Interactions between the existing natural fractures and the hydraulic fracture that result in both complex fracture growth and excessive fluid loss. In addition, subsequent injections increase fracture complexity and fluid loss by opening more natural fractures.

?? Well orientation and fracture initiation procedures. Initiating the zone 3 fracture treatment with low viscosity linear gel increased fracture complexity.[7] In addition, coincidence of the natural fracture orientation and the orientation of "starter" hydraulic fractures further increases fracture complexity when low viscosity fluid is used to initiate the hydraulic fracture.

The rock mechanics study provided important insights into the potential mechanisms that could have resulted in the SA-1C treatment problems. The primary issues appeared to be fracture initiation procedures and the interaction of the hydraulic fracture with pre-existing natural fractures or fissures.

SA-4: Zones 1, 2, & 3

Based on the results of the rock mechanics study and the initial SA-1C treatments, a second set of propped fracturing treatments were conducted on the first three zones in the SA-4 well. The SA-4 was drilled almost parallel to the hydraulic fracture direction. Thus, less complex fracture initiation was expected due to the more favorable longitudinal fracture growth with respect to the wellbore. Several issues were evaluated during these treatments:

- Perforated interval length (6-ft versus 1-ft)
- Proppant size (20/40 versus 16/30)
- Initiation procedures using cross-linked gel
- Proppant slug design
- 100-mesh sand concentration
- Effect of shutdowns on fracture complexity

SA-4 Zone-1 Results. The first zone stimulated in the SA-4 well was perforated using a 1-ft gun (6-ft gun is standard) to evaluate the effect of perforated interval length on fracture complexity. The mini-frac was eliminated from zone 1 to minimize any complexities associated with a shutdown and the subsequent re-initiation of the fracture with linear gel (used to flush the mini-frac). Extreme care was taken during the fracture initiation to ensure that cross-linked fluid was placed as close the perforations as possible. The surface lines were initially flushed with cross-linked gel prior to circulated cross-linked fluid to the bottom of the work-string (**Figure 10**). 100-mesh sand at 1-ppg was added to the latter portion of the circulation stage in an attempt to reduce fracture complexity upon initiation (see Figure 10). In addition, the proppant size was reduced from 16/30 to 20/40-mesh for the initial SA-4 treatments to evaluate the effect of proppant size on treatment success. Therefore, most reasonable precautions were taken to minimize fracture treatment problems. However, the SA-4 Zone 1 treatment screened-out even with these precautions in place.

The layer data for zone 1 are shown in **Table 4**, while the treatment data are provided in Figure 15. The SA-4 Zone 1 treatment data show a modest fracture initiation pressure of about 1700-psi, significantly less than SA-1C Zone 2 (Figure 2, about 3300-psi). In addition, the annulus pressure during the pad is about 1300-psi, 700-psi lower than the SA-1C Zone-2 treatment, indicating modest tortuosity and fracture complexity in SA-4 Zone 1. A small 1-ppg proppant slug was pumped, exhibiting a minor pressure increase of about 200-psi when it passed through the perforations However, significant pressure increases were exhibited when the higher concentration proppant slugs reached the perforation, indicating insufficient fracture width to accept 20/40-mesh proppant (Figure 10). It should be emphasized that about 900 bbls of cross-linked fluid was pumped prior to the second proppant slug (the first major pressure increase, Figure 10).

Table 4 – SA-4, Zone 1 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9338	Upper Ekofisk	3.4
9361	Middle Ekofisk	4.0
9371	Lower Ekofisk	2.8
9407	Tight zone	4.0
9443[(1)]	Tor	1.8
9564	Shale	3.0

Note (1): Zone 1 perfs = 9500-ft TVD

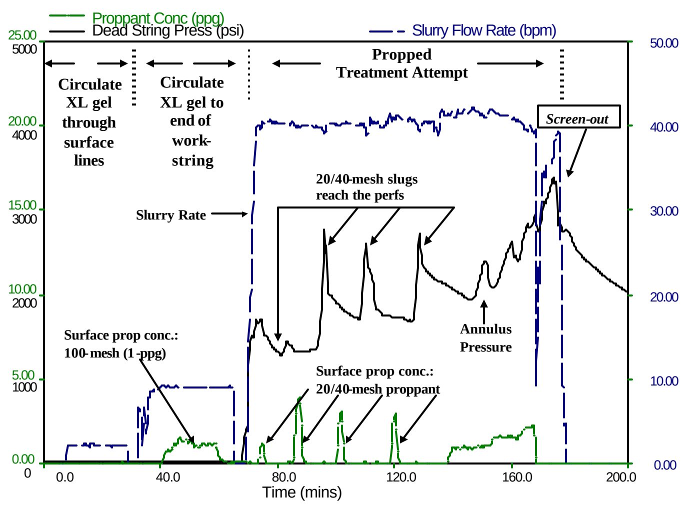

Figure 10 – SA-4 zone 1 treatment data

The Zone 1 treatment continued after four proppant slugs were pumped, although the reaction to the proppant slugs indicated significant proppant entry problems. A very modest sand schedule was utilized, but the treatment started screening-out immediately when the proppant reached the perforations (see Figure 10) and only about 100 Klbs of proppant was placed in the formation. Fracture modeling evaluations indicated modest fracture complexity and very low fluid efficiency (less than 10%).

The Zone 1 treatment showed that fracture initiation with cross-linked fluid containing 100-mesh sand probably resulted in acceptable levels of both fracture complexity and tortuosity, as evidenced by the modest annulus pressures compared to the SA-1C Zone 2 treatment. However, the initiation procedures and proppant slug strategy used in the SA-4 Zone 1 treatment failed to control excessive fluid loss that most likely resulted from the activation of natural fractures or fissures.

SA-4 Zone-2 Results. The second zone in the SA-4 well was perforated using a 6-ft gun (standard). The treatment data are shown in **Figure 11** for reference and the layer data are provided in **Table 5**. The initial cross-linked gel and 100-mesh sand circulation stage is similar to Zone #1, with one important difference – the 100-mesh sand was pumped at concentration of 1 to 3.5-ppg. The shutdown after injection #1 was due to a plugged annulus. As Figure 11 shows, there were no annular pressure measurements until the rig pumped down the annulus to clear the obstruction (about 200 minutes into the job). A 1-4 ppg 20/40 RCS slug was pumped during injection #1 and easily passed through the perforations, indicating no proppant entry problems. After the shut-down, a 1-6 ppg 20/40 RCS slug was pumped during injection #2 and resulted in a 1000+ psi pressure increase when it reached the perforation (about 230 minutes). Due to the clear proppant entry problems, a second shutdown was performed to evaluate treatment options.

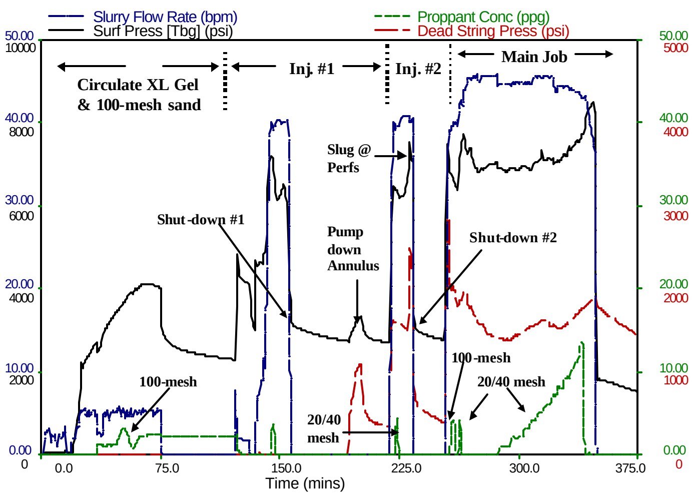

Figure 11 – SA-4 zone 2 treatment data

The apparent success of higher concentrations of 100-mesh sand during injection #1 prompted the re-application of this technique after injection #2, followed by 1-4 ppg 20/40 RCS slug. The results were very positive, with the 20/40-slug easily passing through the perforations, showing no evidence of proppant entry problems. The main treatment placed 450,000 lbs of 20/40 RCS at concentrations up to 12-ppg. This was the first evidence that 100-mesh sand concentration was critical to treatment success in the lower porosity zones.

Table 5 – SA-4, Zone 2 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9344	Upper Ekofisk	3.4
9364	Middle Ekofisk	4.0
9374	Lower Ekofisk	2.8
9403	Tight zone	4.0
9436$^{(1)}$	Tor	1.8
9544	Shale	3.0

Note (1): Zone 2 perfs = 9479-ft TVD

The subsequent analysis of the SA-4, zone-2 treatment indicated that fluid loss had increased dramatically after the first shutdown, while fracture complexity had also increased (but to a lesser degree). The mini-frac (first shutdown) G-function analysis is shown in **Figure 12**, indicating a fracture closure pressure gradient of about 0.74 psi/ft and a fluid efficiency of 45%. Figure 12 indicates pressure dependent leakoff (into natural fractures or fissure) and is a warning sign of potential treatment problems. The fluid efficiency for the second injection (when a proppant slug screen-out almost occurred) was estimated at about 10% or less. There was no 100-mesh sand used during the first re-initiation to control excessive fluid loss into natural fractures/fissures that were indicated during the initial mini-frac pressure decline. The subsequent use of 1-4 ppg 100-mesh sand controlled excessive fluid loss and allowed the treatment to be successfully pumped.

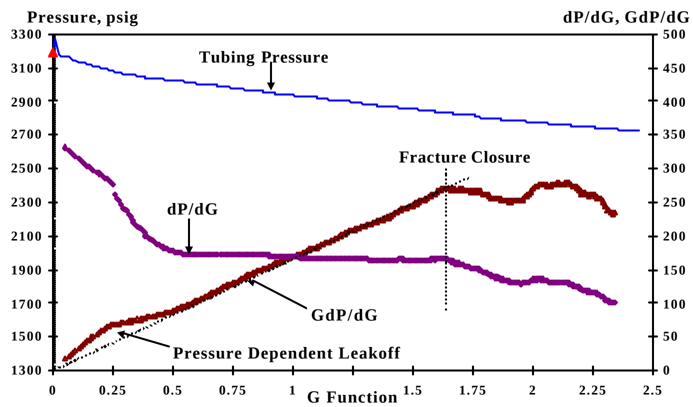

Figure 12 – SA-4 zone 2, injection #1 pressure decline

The net pressure history match of the SA-4 zone-2 propped treatment is shown in **Figure 13**. The fracture modeling indicated a fluid efficiency of about 20% during the propped treatment, much lower than indicated from the mini-frac. The net pressure match did not require the introduction of fracture complexity or tortuosity, indicating that the lower fluid efficiency during the propped treatment was primary due to additional leakoff into natural fractures/fissures that were activated during the two shutdowns. The predicted fracture geometry for zone 2 is shown in **Figure 14**. The modeling shows a propped fracture length of about 280-ft and an average proppant concentration of 4-ppsf. Coverage of the entire Tor and Ekofisk interval is predicted. The fracture modeling shows a proppant concentration of 7-ppsf in the more productive Tor interval, resulting in ***in-situ*** dimensionless fracture conductivity (FCD) of about 5.

The application of 3-4 ppg 100-mesh sand slugs appears to control excessive leakoff into natural fractures/fissure, but still may not completely mitigate the problems associated re-initiation of the fracture with linear gel after each shutdown.

SA-4 Zone 3 Results. The third zone in the SA-4 well was perforated using the standard 6-ft gun (6 spf). The treatment was designed using the zone-3 results and included a 1-4 ppg 100-mesh sand slug in the pad to control excessive fluid loss. The mini-frac was omitted to eliminate any potential problems associated with a shutdown and the subsequent re-initiation of the fracture with linear gel. The zone-3 design was very similar to the zone-2 propped treatment. The layer data for zone 3 are summarized in **Table 6** and are very similar to the previous two zones in the SA-4 well. The treatment data are shown in **Figure 15** and shows that the treatment was pumped with no indications of any proppant entry problems. The application of higher concentration of 100-mesh sand slugs (4-ppg) in the pad, combined with initiating the fracture with cross-linked fluid, appears to control excessive fluid loss and fracture complexity. In addition, an adequate tip screen-out (TSO) was achieved even though the mini-frac was eliminated and a conservative pad size was pumped based on the zone-2 treatment behavior.

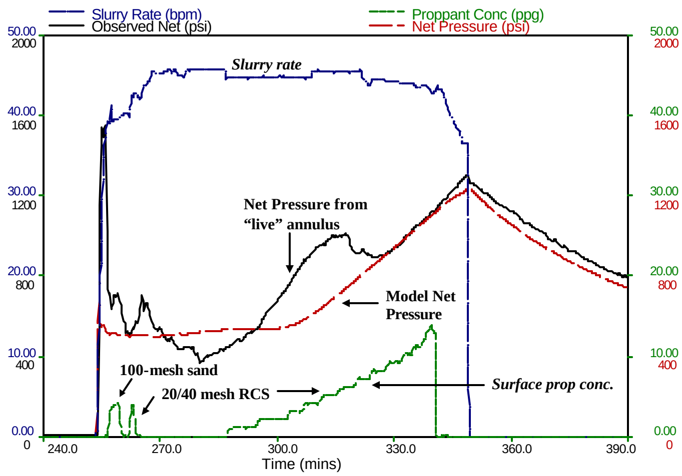

Figure 13 – SA-4 zone 2, net pressure match

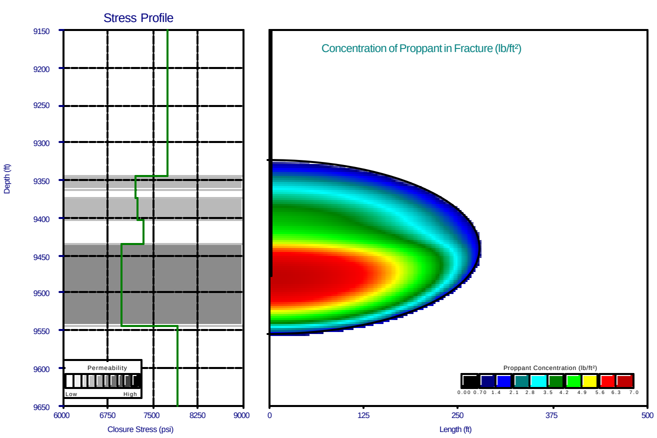

Figure 14 – SA-4 zone 2, predicted fracture geometry

SA-3 Zone-1. The SA-3 well was the last we completed in the batch fracturing programs (Dec.1999 to Jan. 2000). The SA-3 well was drilled essentially parallel to the preferred fracture direction. As with most SA wells, the initial zones at the "toe" of the well exhibited low porosity – about 20%-25%. The corresponding higher Young's modulus appears to cause more frequent fracture treatment problems. The first zone in the SA-3 well screened out very early in the propped treatment, similar to other low porosity zones in SA-1C and SA-4. The layer data are shown in **Table** 7. The treatment data for the SA-3 Zone-1 treatment are shown in **Figure 16** and illustrates the severity of the screen-out when only 2-ppg 20/40-mesh RCS was entering the perforations. The fracture initiation procedures for SA-3 Zone-1 utilized a cross-linked fluid, 1-4 ppg 100-mesh sand, and a 1-4 ppg proppant slug (see Figure 16), similar to previous treatments. The mini-frac initiation pressure was modest, about 2000-psi (see Figure 16, 200-220 minutes). The annulus pressure at the end of the mini-frac was about 1300-psi, with only minor the near-wellbore tortuosity of about 300-psi. The mini-frac was modeled using a simple geometry (1-fracture) and there were no indications of any potential fracture treatment problems.

Table 6 – SA-4, Zone 3 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9318	Upper Ekofisk	3.4
9338	Middle Ekofisk	4.0
9348	Lower Ekofisk	2.8
9377	Tight zone	4.0
9410(1)	Tor	1.7
9538	Shale	3.0

Note (1): Zone 3 perfs = 9465-ft TVD

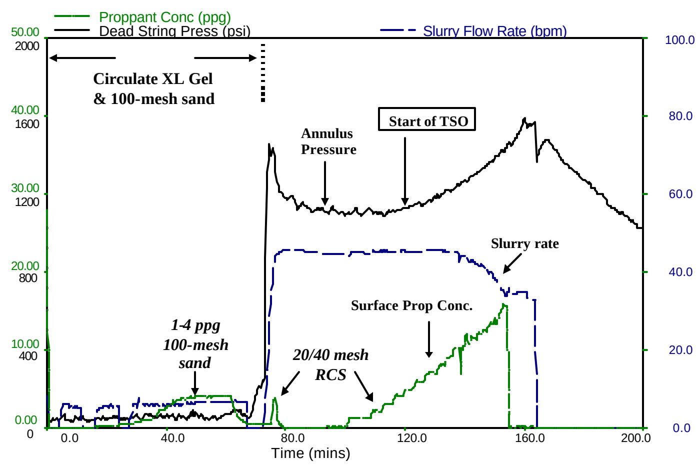

Figure 15 – SA-4 Zone 3 treatment data

Table 7 – SA-3, Zone 1 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9220	Upper Ekofisk	4.8
9279	Middle Ekofisk	2.8
9305	Lower Ekofisk	3.4
9351	Tight zone	4.8
9397(1)	Tor	2.8
9610	Shale	3.0

Note (1): Zone 1 perfs = 9478-ft TVD

The mini-frac pressure decline analysis, shown in **Figure 17**, indicated a fracture closure pressure of 0.74 psi/ft and a fluid efficiency of 35%. The mini-frac GFunction analysis (see Figure 17) did exhibit pressure dependent leakoff or "fissure opening" very early in the pressure decline.

The 100-mesh sand concentration in the pad of the SA-3 Zone-1 treatment was pumped at concentrations of only 1.5-

ppg. This lower concentration of 100-mesh sand does not appear to control fracture complexity and excessive leakoff (as was evidenced by the early SA-4, zone 1 & 2 treatments). The SA-3 Zone-1 propped treatment screen-out was modeled using both fracture complexity (2-fractures) and excessive leakoff (less than 10% fluid efficiency). The absence of sufficient concentrations of 100-mesh sand resulted in excessive leakoff and increased fracture complexity during the zone 1 propped treatment, causing a screen-out as proppant reached the perforations. It should be noted that the fracture re-initiation pressures for the propped treatment were about 800-psi higher than the pumping pressure at the end of mini-frac, indicating that fracture complexity or tortuosity increased after the mini-frac shutdown (Figure 16).

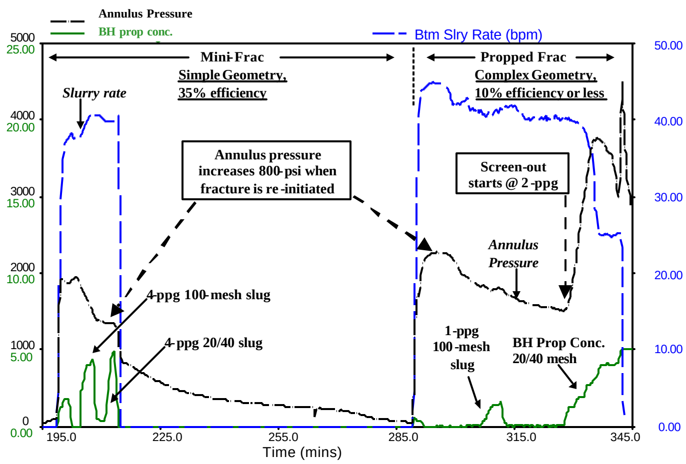

Figure 16 – SA-3 Zone 1 treatment data

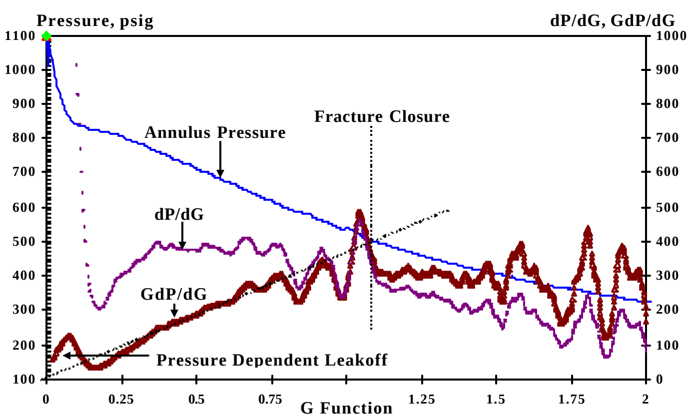

Figure 17 – SA-3 Zone 1, mini-frac pressure decline analysis

In most SA treatments, the addition of 1-4 ppg 100-mesh plus a 1-4 ppg proppant slug (20/40 or 16/30-mesh) will mitigate the detrimental effects of re-initiating the propped treatment with linear gel. However, neither of these techniques was applied in SA-3, zone 1. In SA-3 zones 2-4, the 100-mesh sand concentration in the pad was increased to 1-4 ppg, proppant slugs were added to the pad following the 100-mesh slug, and the mini-frac was omitted from the treatments. The zone 2-4 treatments did not experience excessive leakoff or fracture complexity and were successfully pumped. Mini-fracs were added to the treatment procedures for selected zones (mostly higher porosity, lower modulus zones) after zone 4 with no detrimental affects.

SA-2 Zone 3

The application step-rate tests (SRTs) were evaluated in zones 2 & 3 of the SA-2 well. The SRTs were performed after the mini-frac using 40# linear gel (the mini-frac flush fluid). The zone 3 results are detailed in this section to illustrate the problems associated with initiating of re-initiating hydraulic fractures in SA with low viscosity fluid. The zone 3 layer data are shown in **Table 8**. **Figure 18** shows the injection rates and annulus pressures for the zone-3 mini-frac and step-rate test. The instantaneous shut-in pressure (ISIP) for the mini-frac was about 1000-psi, while the SRT exhibits an ISIP of about 1750-psi. The 750-psi increase in ISIP after the SRT is an indication of increased fracture complexity, as the low rate injection of a low viscosity linear gel should exhibit a lower ISIP (or net pressure) based solely on simple fracture mechanics. **Figure 19** compares the ISIPs for the mini-frac and SRT, showing both a 750-psi increase in ISIP and a 500-psi offset in annulus during the subsequent pressure decline. The annulus pressure after the SRT is 500-psi higher than it was after the mini-frac, even though a very small volume of fluid was injected during the SRT. The higher annulus pressure indicates higher net pressure and thus greater fracture complexity.

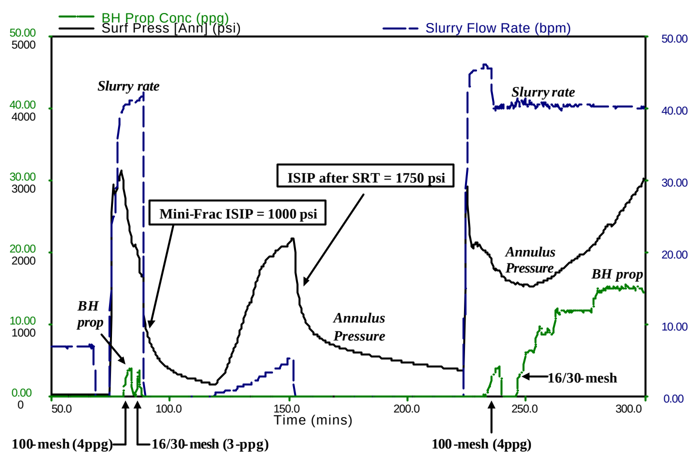

Figure 18 – SA-2 zone 3 treatment data, including mini-frac & SRT

In theory, a step-rate test should provide an upper bound for fracture closure stress by defining the fracture extension pressure. It is many-times assumed that the fracture extension pressure is 100-300 psi above fracture closure pressure based on conventional fracture modeling theory. However, if there are any fracture complexities, tip-effects, tortuosity, etc., this assumption is not valid and the SRT can yield misleading results. In South Arne, initiating fracture treatments using high viscosity fluid is very important to minimize fracture complexities. However, the effects of re-initiating the fracture using low viscosity fluid were not well understood. The zone 3 SRT provides clear evidence that re-initiating fractures using low-viscosity fluid can increase fracture complexity.

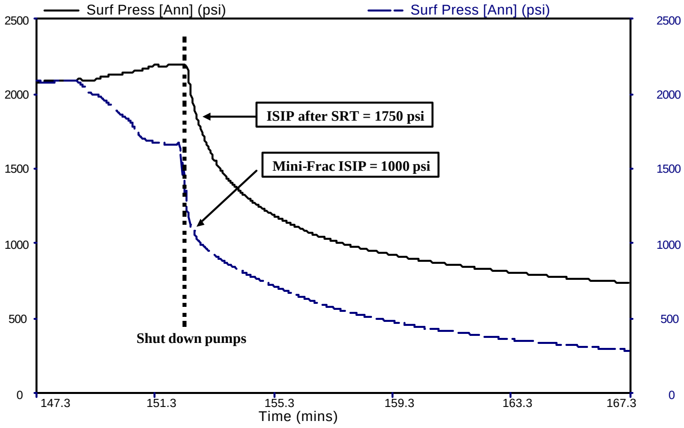

Figure 19 – SA-2 zone 3 ISIP comparison: mini-frac & SRT

Table 8 – SA-2, Zone 3 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9341	Upper Ekofisk	2.4
9371	Middle Ekofisk	1.7
9420	Lower Ekofisk	1.2
9489	Tight zone	5.7
9505(1)	Tor	0.8
9620	Shale	3.0

Note (1): Zone 1 perfs = 9531-ft TVD

The mini-frac G-function analysis is shown in **Figure 20**, indicating a fracture closure pressure of 7075-psi (about 600-psi annulus pressure). The reliability of the zone 3 mini-frac analysis is very high, as the pressure decline is very well behaved and the closure pressure gradient of 0.745 psi/ft is within expected limits. The analysis of the zone 3 SRT is shown in **Figure 21** and indicates a fracture extension pressure of about 1800-psi. Based on the SRT, we would estimate a closure pressure of about 1500 - 900 psi higher than indicated from the previous mini-frac analysis and 500 psi higher than the mini-frac ISIP. The SRT analysis is clearly dominated by fracture complexity resulting from the re-initiation of the fracture using linear gel.

Figure 22 shows the G-function analysis of the pressure decline after the zone 3 SRT. The G-function superposition curve (GdP/dG) exhibits the strong signature of pressure dependent leakoff for an extended time period during the post-SRT decline. In addition, fracture closure is not clearly defined. The preponderance of evidence that supports the hypothesis that the combination of a low rate, low viscosity re-initiation of the fracture and a mini-frac shutdown significantly increased fracture complexity: (1) increased ISIP and net pressure after the SRT, (2) strong pressure dependent leakoff signature after the SRT, and (3) high injection pressures and fracture extension pressure during the SRT.

Although fracture complexity increased dramatically during the SRT, the application of 1-4 ppg 100-mesh sand successfully reduced fracture complexity and excessive leakoff, allowing the treatment to be pumped using 16/30-mesh proppant (Figure 18).

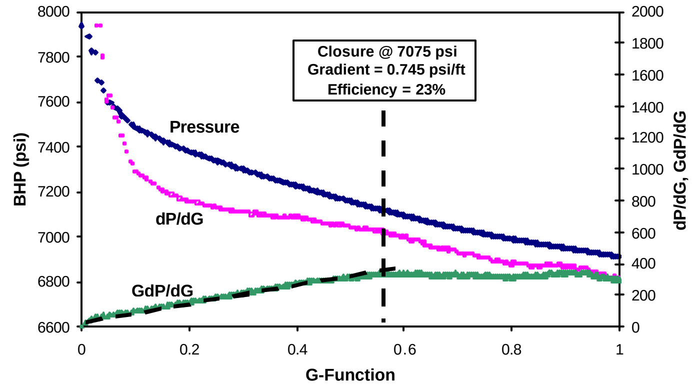

Figure 20 – SA-2 zone 3 mini-frac pressure decline

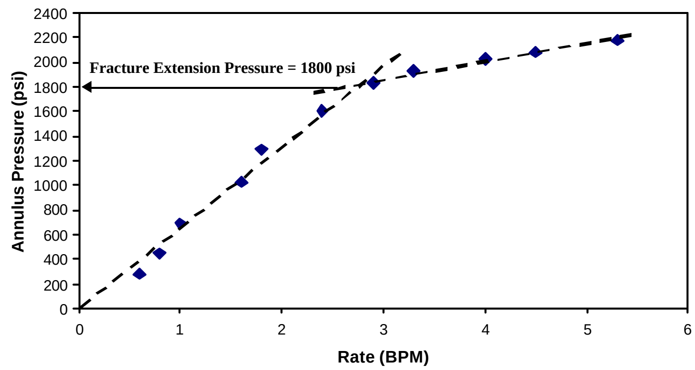

Figure 21 – SA-2 zone 3 Step-Rate-Test (SRT)

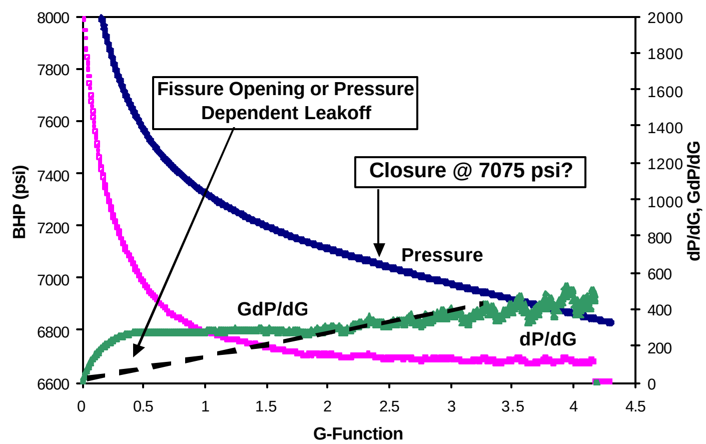

Figure 22 – SA-2 zone 3 pressure decline after the SRT

Summary

The integration of fracture treatment behavior, rock mechanics, and pressure decline analyses provided a preponderance of evidence indicating that the activation or dilation of natural fractures or fissures was a primary cause for treatment failures. The ability to control excessive fluid loss and complexity caused by the activation of natural fractures or fissures is very sensitive to the concentration of 100-mesh sand, requiring 3-4 ppg to effectively mitigate problems. Field data from the first 64 fracture treatments indicated that fracture treatment problems were much more likely in lower porosity zones. The lower porosity zones exhibit higher Young's modulus, which results in less fracture width and much more pronounced pressure dependent leakoff behavior (fissure opening) compared to the higher porosity intervals. The importance of identifying complexities in horizontal well propped fracture completions is critical and has been documented in other environments.[9,10]

Conclusions

1. Fracture initiation procedures are critical to the success of propped fracture treatments in South Arne. Initiating fractures with high viscosity fluid containing 100-mesh sand significantly reduces treatment problems.

2. Excessive fluid loss and increased fracture complexity can result from the activation or dilation of natural fractures/fissures. 100-mesh sand slugs at concentrations of 3-4 ppg can effectively control excessive fluid loss into natural fractures/fissures in the South Arne Field.

3. G-function analysis that includes both the derivative and superposition curves can be used to identify "fissure opening" or pressure dependent leakoff in South Arne.

4. Re-initiating hydraulic fractures using low viscosity fluid can significantly increase fracture complexity and fluid loss in South Arne. However, the re-application of 4-ppg 100-mesh sand slugs can effectively reduce fracture complexity and leakoff to acceptable levels.

5. Low porosity zones are prone to treatment problems (fracture complexity & excessive leakoff) that can be aggravated by successive injections & shutdowns. Eliminating the mini-frac in these zones may reduce treatment risks without sacrificing TSO design criteria.

6. Treatment problems **were not** dependent on wellbore orientation when proper fracture initiation procedures were employed in South Arne.

7. Perforated intervals less than 6-ft do not reduce fracture complexity in South Arne.

8. Increasing proppant size from 20/40 to 16/30 mesh does not increase placement problems when proper fracture initiation and leakoff control procedures are used. 90% of the SA treatments were pumped using 16/30-mesh proppant, with only 3 screen-outs.

Nomenclature

Klbs = *1000 pounds*
ppg = *pounds of proppant added per gallon of fluid*
ppsf = *pounds of proppant/ square foot of fracture area*
RCS, RCP = *Resin coated sand, Resin coated proppant*
SA = *South Arne*
TSO = *tip screen-out*

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